BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313)	))))))	Docket No. 2020-125-E

SURREBUTTAL TESTIMONY

OF

DAVID E. DISMUKES, Ph.D.

ON BEHALF OF

SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS

December 18, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am the same person that prepared and pre-filed Direct Testimony on the behalf of the South Carolina Department of Consumer Affairs ("DCA") on November 10, 2020.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to elements of the Rebuttal Testimonies of Kevin R. Kochems and Allen W. Rooks on behalf of Dominion Energy South Carolina, Inc. ("DESC" or the "Company").

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My balance of testimony is organized into the following sections:

- Section II: Class Cost of Service Study
- Section III: Rate Design
- Section IV: Conclusions and Recommendations

Q. HAVE YOU PREPARED ANY EXHIBITS SUPPORTING YOUR SURREBUTTAL TESTIMONY?

A. Yes. The following Surrebuttal Exhibits were prepared under my direction and control:

- Exhibit DED-1 – Survey of Southeastern IOU Transmission Plant Cost Allocations.
- Exhibit DED-2 – Comparison of BFC to Customer-related Costs.

II. CLASS COST OF SERVICE STUDY

Q. PLEASE DISCUSS THE COMPANY'S CRITICISMS OF YOUR CLASS COST OF SERVICE STUDY RECOMMENDATIONS.

A. The Company disagrees with my recommendation to use the Average and Peak ("A&P") cost allocation method to allocate costs associated with the Company's production plant facilities[1] and my statements that the Company's allocation of demand-related costs associated with transmission plant facilities is inconsistent with the methodology used by the Federal Energy Regulatory Commission ("FERC").[2]

Q. WHY DOES THE COMPANY DISAGREE WITH THE USE OF YOUR PROPOSED A&P METHOD?

A. The Company states that regulators should maintain consistency in the ratemaking process to prevent improper swings in rates between customer classes.[3] The Company notes that it, and its predecessor South Carolina Electric & Gas Company ("SCE&G"), have used the current single coincident peak cost allocation method to allocate costs associated with production plant facilities for at least the last 38 years.[4]

Q. IS CONSISTENCY IMPORTANT IN THE RATEMAKING PROCESS?

A. Yes. However, a utility's Class Cost of Service Study ("CCOSS") should additionally accurately represent how a utility's costs are incurred pursuant to the

[1] Rebuttal Testimony of Kevin R. Kochems at 2:18.

[2] *Id.* at 5:10-13.

[3] *Id.* at 2:18-20.

[4] *Id.* at 2:20 to 3:2.

principle of cost-causation. In this case this argument surrounds the appropriate ratemaking treatment of the Company's production plant costs. My Direct Testimony provides evidence that the Company's current CCOSS cost allocation method inappropriately assigns rate increases of more than $5.0 million to residential service customers and more than $2.4 million to small general service customers compared to the assignments under my proposed A&P cost allocation method.[5]

Q. DOES THE COMPANY ARGUE THAT ITS EXISTING CCOSS COST ALLOCATION METHODS SHOULD NEVER BE MODIFIED?

A. No. The Company recognizes that it is appropriate to revisit appropriate cost allocation methods.[6] However, the Company notes that significant changes should be measured and vetted by all stakeholders. The Company suggests that changes in cost allocation methodologies, like the ones I am proposing, should be deferred for further evaluation in the Company's next general rate case (not the current rate case), where the Company and other stakeholders will have a chance to fully study the potential alternative cost allocation methodologies.[7]

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATIONS THAT YOUR PROPOSED COST ALLOCATION METHODS BE DEFERRED UNTIL THE NEXT BASE RATE CASE?

[5] Direct Testimony of David E. Dismukes at 3, Table 1.

[6] Rebuttal Testimony of Kevin R. Kochems at 3:5-10.

[7] *Id.* at 6:3-7.

A. No. Contrary to the Company's assertions, I have measured the impacts from my proposed change in cost allocation methods and presented these results in my Direct Testimony. Furthermore, parties to this proceeding will have the chance to respond to my proposed changes through Surrebuttal Testimony filed concurrently with this testimony. Parties will additionally have the chance to offer alternatives to my proposed changes.

Q. HAS THE COMPANY MADE ANY OTHER ARGUMENTS OPPOSING YOUR COST ALLOCATION METHODS?

A. Yes. The Company states that an A&P, or any alternative method of cost allocation which allocates a portion of production costs on energy usage, would not adhere to the principle of cost causation. Specifically, the Company claims that it must provide adequate generating capacity to meet the maximum demands of its customers, regardless of when that peak demand occurs.[8] The Company alludes to actual load analysis and characteristics of its system potentially rendering cost allocation methods "appropriate in other locations and jurisdictions," not appropriate for the allocation of costs associated with its system.[9]

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT PEAK DEMAND NEEDS FULLY DRIVE PRODUCTION PLANT INVESTMENTS?

A. No. As I explained in my Direct Testimony, electric generating units ("EGUs") are designed to serve both energy and demand/capacity needs of a utility.[10] This is

[8] *Id.* at 4:8-11.

[9] *Id.* at 3:15-19.

[10] Direct Testimony of David E. Dismukes at 21:19 to 22:12.

readily observable when considering how utilities dispatch generation units. Generation units defined as baseload units are designed with low operating costs in mind and thus operate during most hours of the year. These baseload units also often have relatively large upfront capital requirements to construct. Peaking units, on the other hand, are often relatively inexpensive to initially construct and have additional operational flexibilities relative to baseload units. Peaking units, however, additionally have higher operating costs and are thus typically held in reserve and only utilized by a utility during periods of peak demand. If the requirement to meet the maximum demands of its customers were the only consideration when deciding to construct or purchase a new EGU, the Company would not invest in new baseload generation units.

Q. DOES THE COMPANY ADDRESS THESE DIFFERENCES IN GENERATION RESOURCE CHARACTERISTICS IN ITS REBUTTAL TESTIMONY?

A. No, the Company's Rebuttal Testimony is silent on this issue. I, however, provided evidence in my Direct Testimony that a significant portion of the Company's generation fleet supplies non-capacity needs of the utility based on an analysis of individual generation units' capacity factors.[11]

Q. PLEASE DISCUSS THE COMPANY'S CRITICISMS OF YOUR TRANSMISSION COST ALLOCATION RECOMMENDATIONS.

A. The Company states that I did not provide a full recitation of FERC's position on the appropriate cost allocation method to utilize in assigning costs associated with transmission plant assets. Specifically, the Company admits that FERC favors a

[11] *Id.* at 23:15-23.

cost allocation based on the average of 12-monthly coincident peaks ("12-CP"), but notes that utilities are free to employ alternative allocation methods with appropriate justification.[12]

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT?

A. No, since the Company provides no empirical nor policy evidence supporting its claims. Exhibit DED-1, however, presents a survey of the transmission plant cost allocation methods employed by Southeastern electric utilities involved in at least one rate case in the past 10 years. The survey shows that 45.5 percent of all Southeastern electric utilities allocate costs associated with transmission plant investments on the basis of 12-CP. Of the six utilities that do not use a 12-CP cost allocation, three are Duke Energy Carolina affiliates, with the other three being affiliates of the Company. Indeed, removing the Company and its affiliates from this survey finds that 62.5 percent of Southeastern electric utilities use a 12-CP cost allocation to allocate costs associated with transmission plant investments. These include large regional utilities such as Florida Power & Light Company and Georgia Power. This is consistent with the general view that most utilities and jurisdictions seek to establish consistency with FERC cost allocation processes which establish appropriate transmission rates. As the Company notes, FERC has expressed a preference for using 12-CP to allocate costs associated with investment in transmission plant facilities.

Q. DOES YOUR TRANSMISSION PLANT COST ALLOCATION RECOMMENDATION HAVE ANY IMPACTS IN THE CURRENT PROCEEDING?

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[12] Rebuttal Testimony of Kevin R. Kochems at 5:1-13.

A. No. As I stated in my Direct Testimony, the Company does not calculate coincident peak contributions by class on a monthly basis.[13] Without monthly system CP information on a class basis one cannot calculate the appropriate 12-CP allocation factor to assign transmission plant investment costs to Company customer classes. I therefore only recommend that the Commission require the Company to gather this monthly system coincident peak information on a customer class basis in the future, so the appropriateness of a 12-CP allocation of costs associated with transmission plant investments can be assessed at a later date. To this end, I also recommend that the Commission require the Company to file an alternative CCOSS in its next base rate case filing which allocates costs associated with electric transmission plant investments on a 12-CP basis.

III. RATE DESIGN

Q. DOES THE COMPANY SUPPORT RETAINING CURRENT BASIC FACILITIES CHARGES?

A. No. The Company notes that its proposed increase to residential Basic Facilities Charges ("BFC") from $9.00 per month to $11.50 per month would closely align its customer charges with neighboring utilities.[14] The Company also criticizes my omission regarding that the Company's proposed BFCs, even after being increased, would be lower than its determined cost to serve for all but one customer class.[15]

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[13] Direct Testimony of David E. Dismukes at 26:20 to 27:2.

[14] Rebuttal Testimony of Allen W. Rooks at 16:9-13.

[15] *Id.* at 18:16-18.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED INCREASE IN THE RESIDENTIAL BFC WOULD CLOSELY ALIGN ITS CUSTOMER CHARGES WITH NEIGHBORING UTILITIES?

A. No. As I note in my Direct Testimony, there are three regional electrical Investor-Owned Unities ("IOUs") that have residential customer charges that are lower than the Company's current residential BFC.[16] These include the Company's Virginia affiliate, Dominion Virginia Power, which currently charges its residential customers a monthly customer charge of only $6.58 per month, 26.9 percent less than that currently charged by the Company. The Company's proposed increase to its residential BFC would notably weaken the Company's standing relative to other regional electric IOUs.

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSED INCREASE TO BFC RATES WOULD STILL BE LESS THAN CUSTOMER-RELATED COST TO SERVE?

A. No. The Company presented an analysis in its Direct filing claiming that its current BFCs, and even its proposed BFCs, were significantly less than its determined customer-related cost of service for all but its large general service customer class.[17] The Company's analysis however is highly flawed, since it includes costs associated with distribution plant facilities that are demand-related and not customer-related, as noted by other intervenors to this proceeding.[18] Specifically,

[16] Direct Testimony of David E. Dismukes at 35:15 to 36:6.

[17] *See*, Direct Testimony of Allen W. Rooks, Exhibit AWR-2.

[18] Direct Testimony of Scott J. Rubin at 8:9-21.

the Company includes as customer-related all costs associated with secondary lines and a portion of secondary transformers, which are typically considered demand-related and not customer-related.

Q. DOES THE COMPANY DISPUTE THAT THE REFERENCED FACILITIES ARE DEMAND-RELATED?

A. Yes. The Company claims that secondary lines and a portion of secondary transformers are customer related as "costs per customer are similar within each customer class, and not dependent on customer demand…"[19] However, the Company's own CCOSS contradicts this assertion. Within the Company's CCOSS, customer class allocations of secondary lines and secondary transformers are assigned to customer classes based on an allocation factor listed as "C35,"[20] which the Company defines as "Billing Demand at Customer Level-Secondary."[21] In other words, in contradiction to the Company's statement that secondary lines and secondary transformers are not dependent on customer demand, the Company's CCOSS assigns costs associated with these facilities to customer classes based on a measurement of customer demands.

Q. HAVE YOU CALCULATED THE COMPANY'S CURRENT BFC RELATIVE TO CUSTOMER-RELATED COST OF SERVICE?

A. Yes. Exhibit DED-2 presents a comparison of the Company's customer-classified costs included in its CCOSS to current BFC revenues by customer class. These

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[19] Rebuttal Testimony of Allen W. Rooks at 16:4-6.

[20] Direct Testimony of Kevin R. Kochems, Exhibit KRK-1 at 3.

[21] Company Response to Data Request ORS 2-40; note that the Company additionally assigns a portion of secondary transformers as "capacity-related" based on the allocation factor D-35, which is defined as "KW NCP Demands at Generation Level (Secondary)."

customer-related costs include depreciation expenses associated with distribution services[22] and meters, fair return on investment in distribution services and meters, and costs associated with customer account activities such as billing services. As shown in Exhibit DED-2, all of the Company's customer classes currently fully recover customer-related costs through the existing BFC. This includes the residential customer class, which is estimated to currently recover 110.2 percent of customer-related costs through the existing BFC.

IV. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. SHOULD THE COMMISSION DEFER THE CONSIDERATION OF YOUR PROPOSED COST ALLOCATION METHODS UNTIL NEXT BASE RATE CASE?

A. No. Contrary to the Company's assertions, I have measured the impacts from my proposed change in cost allocation methods and presented these results in my Direct Testimony. Furthermore, parties to this proceeding will have the chance to respond to my proposed changes through Surrebuttal Testimony filed concurrently with this testimony. Parties will additionally have the chance to offer alternatives to my proposed changes.

Q. DO YOU CONTINUE TO RECOMMEND THAT THE COMMISSION REQUIRE THE COMPANY GATHER MONTHLY SYSTEM COINCIDENT PEAK INFORMATION ON A CUSTOMER CLASS BASIS AND FILE AN

[22] Note that the Company additionally allocates distribution services on the basis of secondary billing demand, implying the Company classifies such systems as capacity/demand-related. These facilities are typically viewed as being related to the provision of service to individual customers, and thus are included in my analysis of customer-related costs.

ALTERNATIVE CCOSS ALLOCATING COSTS ASSOCIATED WITH TRANSMISSION PLANT FACILITIES ON A 12-CP BASIS?

A. Yes. As I stated in my Direct Testimony, the Company does not calculate coincident peak contributions by class on a monthly basis. Without monthly system CP information on a class basis, one cannot calculate the appropriate 12-CP allocation factor to assign transmission plant investment costs to Company customer classes. I therefore only recommend that the Commission require the Company to gather this monthly system coincident peak information on a customer class basis in the future, so the appropriateness of a 12-CP allocation of costs associated with transmission plant investments can be assessed at a later date. To this end, I also recommend that the Commission require the Company to file an alternative CCOSS in its next base rate case filing which allocates costs associated with electric transmission plant investments on a 12-CP basis.

Q. DO YOU CONTINUE TO RECOMMEND THAT THE COMMISSION NOT ADOPT THE INCREASES IN BFC PROPOSED BY THE COMPANY?

A. Yes. The Company's proposed increases to residential BFC would notably weaken its standing relative to other regional electric IOUs, such as the Company's Virginia affiliate, Dominion Virginia Power, which currently charges its residential customers a monthly BFC that is 26.9 percent less than that charged by the Company. Furthermore, I find that most Company customer classes currently fully recover customer-related costs through the existing BFC. This includes the residential customer class, which is estimated to currently recover 110.2 percent of customer-related costs through the existing BFC.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

Table of Exhibits

Survey of Southeastern IOU Transmission Plant Cost Allocations

State	Utility	Rate Proceeding	Transmission Plant Cost Allocation
SC	Dominion Energy, South Carolina	Docket No. 2020-125-E	1 CP
FL	Florida Power & Light	D-160021-EI	12 CP
GA	Georgia Power	Docket No. 42516	12 CP
KY	Duke Energy, Kentucky	C-2019-00271	12 CP
MS	Entergy Mississippi	D-2014-UN-0132	12 CP
MS	Mississippi Power	ER15-1404	12 CP
NC	Dominion North Carolina Power	Docket No. E-22, Sub 532	Average and Peak
NC	Duke Energy Progress, North Carolina	Docket No. E-7, SUB 1219	1 CP
NC	Duke Energy, North Carolina	Docket No. E-7, SUB 1214	1 CP
SC	Duke Energy, South Carolina	Docket No. 2018-319-E	1 CP
VA	Dominion Virginia Power	PUR-2018200192	1 CP
		12 CP Allocations:	**5**
		Total:	**11**
			45.5%

Source: Utility Rate Case Filings.

Comparison of BFC Revenues to Customer-Related Costs
Summary of BFR Revenues to Customer-Related Costs

Line Num.		Residential Service	Small General Service	Medium General Service	Large General Service
	BFC Revenues per Customer				
1	Monthly BFC Revenues	$ 5,727,807	$ 1,873,995	$ 477,870	$ 560,625
2	Average Number of Customers	636,387	100,016	2,609	322
3	**Average Monthly BFC Revenues per Customers**	**$ 9.00**	**$ 18.74**	**$ 183.16**	**$ 1,741.07**
	Customer-Related Costs per CCOSS				
4	Annual Customer-Related Costs	$ 62,375,589	$ 17,120,373	$ 2,663,466	$ 675,034
5	Average Number of Customers	636,387	100,016	2,609	322
6	**Average Monthly Customer-Related Costs per Customer**	**$ 8.17**	**$ 14.26**	**$ 85.07**	**$ 174.70**
7	**Average Monthly BFC Revenues per Customer**	**$ 9.00**	**$ 18.74**	**$ 183.16**	**$ 1,741.07**
8	**Average Monthly Customer-Related Costs per Customer**	**$ 8.17**	**$ 14.26**	**$ 85.07**	**$ 174.70**
9	**Monthly BFC Revenues as Percent of Customer-related Costs**	**110.2%**	**131.4%**	**215.3%**	**996.6%**

Source: Company's CCOSS.

Comparison of BFC Revenues to Customer-Related Costs
Detailed Calculations

Line Num.		Residential Service	Small General Service	Medium General Service	Large General Service	
	Basic Facilities Charge Revenues					
1	Average Monthly Revenues	$ 5,727,807	$ 1,873,995	$ 477,870	$ 560,625	
2	Test Year Average Customer Count	636,387	100,016	2,609	322	
3	**Average Monthly BFC Revenue per Customer**	**$ 9.00**	**$ 18.74**	**$ 183.16**	**$ 1,741.07**	**line 3 = line 1 / line 2**
	Customer-Related Costs					
4	Total Distribution Plant	$1,900,406,303	$ 687,651,462	$ 248,642,549	$ 281,628,059	
5	Total Customer-related Distribution Plant	$ 320,718,701	$ 105,719,892	$ 22,245,764	$ 2,976,207	
6	Percent Distribution Plant classified as Customer-related	16.88%	15.37%	8.95%	1.06%	line 6 = line 5 / line 4
	Depreciation Expense					
7	Total Distribution Depreciation Expense	$ 47,115,992	$ 16,980,040	$ 6,118,918	$ 6,864,006	
8	**Distribution Depreciation Expenses classified as Customer-related**	**$ 7,951,447**	**$ 2,610,520**	**$ 547,453**	**$ 72,538**	**line 8 = line 6 * line 7**
	Return on Ratebase					
9	Total Customer-related Distribution Plant	$ 320,718,701	$ 105,719,892	$ 22,245,764	$ 2,976,207	
10	Test Year Rate of Return	5.99%	7.59%	5.74%	4.61%	
11	**Return on Customer-related Distribution Plant**	**$ 19,211,050**	**$ 8,024,140**	**$ 1,276,907**	**$ 137,203**	**line 11 = line 9 * line 10**
	Operations Expenses					
12	Customer Account Expenses	$ 33,788,484	$ 5,293,571	$ 261,677	$ 22,903	
13	Customer Service and Informational Expenses	$ 1,191,109	$ 958,642	$ 356,761	$ 208,890	
14	Sales Expenses	$ 233,500	$ 233,500	$ 220,670	$ 233,500	
15	**Total Customer-related Operational Expenses**	**$ 35,213,092**	**$ 6,485,713**	**$ 839,107**	**$ 465,293**	**line 15 = line 12 + line 13 + line 14**
16	Total Test Year Customer-related Costs	$ 62,375,589	$ 17,120,373	$ 2,663,466	$ 675,034	line 16 = line 8 + line 11 + line 15
17	Conversion to Monthly Costs	12	12	12	12	
18	Test Year Average Customer Count	636,387	100,016	2,609	322	
19	**Average Monthly Customer Costs per Customer**	**$ 8.17**	**$ 14.26**	**$ 85.07**	**$ 174.70**	**line 19 = (line 16 / line 17) / line 18**
20	**Average Monthly BFC Revenue per Customer**	**$ 9.00**	**$ 18.74**	**$ 183.16**	**$ 1,741.07**	**line 3**
21	**Average Monthly Customer-Related Costs per Customer**	**$ 8.17**	**$ 14.26**	**$ 85.07**	**$ 174.70**	**line 19**
22	**Monthly BFC Revenues as Percent of Customer-related Costs**	**110.2%**	**131.4%**	**215.3%**	**996.6%**	**line 22 = line 20 / line 21**

Source: Company's CCOSS.